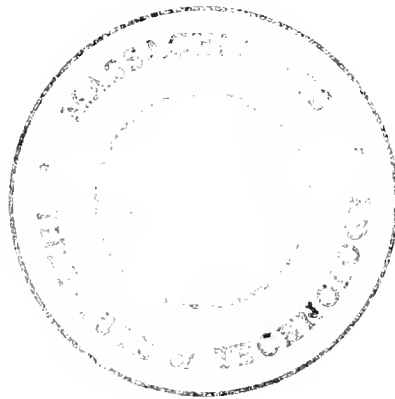


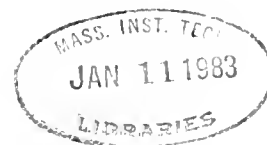
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VERTICAL MARKET ARRANGEMENTS,
RISK-SHIFTING, AND NATURAL
GAS PIPELINE REGULATION

Paul R. Carpenter

September 1982

Working Paper #1369-82

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I. INTRODUCTION

We knew there was going to be some pain and suffering (during the transition to decontrolled wellhead prices), now we've got to minimize the trauma.

Jack E. Earnest, Senior VP*
Texas Eastern Pipeline Co.

The free-market segment of the industry, the producers, should bear the risk that their commodity may be unmarketable above a certain price.

Joseph P. Thomas, Exec. VP*
Peoples Gas Light and Coke

The process of decontrolling the wellhead price of natural gas, begun by the Natural Gas Policy Act of 1978 (NGPA), has started to work major changes on the nature of the business of producing, transporting and distributing natural gas. The increase in wellhead prices, coupled with recession-induced shifts in industrial demand, have caused many major gas pipeline companies to experience a substantial loss of industrial load. This is a new experience within the memories of most pipeline executives, wellhead price controls having held gas prices below the price of competitive fuels since the historic 1954 Supreme Court decision in Phillips Petroleum Co. vs. Wisconsin. Excess demand for gas and the supply shortages and curtailments that accompanied price controls virtually guaranteed that every cubic foot of gas the pipeline

*As quoted in "Gas Pipelines: Priced Into a No-growth Future - Massacre in the Marketplace," Business Week, August 2, 1982, pp.44-48.

Thanks are due to Frank Graves, Henry Jacoby, Robyn McLaughlin, Stewart Myers, Richard Schmalensee, Arlie Sterling and Arthur Wright for their valuable comments and suggestions.

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company purchased from producers could be sold. Absent the reimposition of price controls, those days of market stability are forever past.

In addition to the change in demand conditions, there appears to be a change occurring in the way business is conducted in the gas industry. The gas industry is composed of three tiers: production, transmission and sale-for-use. The federally-regulated gas pipelines, the transmission tier, are the exclusive buyers of large quantities of gas from producers, which they then resell to state-regulated distribution companies and end users. Sales of gas at both ends of the pipeline traditionally have been made under the terms of standard twenty-year, fixed-price, take-or-pay¹ contracts. Evidence (discussed below) indicates that at the producer end of the pipeline the standard contract is giving way to contracts of shorter duration, with flexible price provisions and lower take-or-pay requirements. A trend toward backward integration by pipeline companies into gas production is also apparent.

This paper analyzes these trends in the relationships between gas producers and pipelines under regulation. The term "vertical market arrangements" will be used throughout to denote the hierarchy of possible methods by which gas is purchased. This hierarchy spans the spectrum from vertical integration (in-house production), to long-term contracts, to spot market² arrangements (currently not observed in the gas

¹Take-or-pay clauses require the purchaser to agree to pay for a certain quantity of gas, usually a percentage of the production capability or "deliverability" of the field under contract, even if the purchaser is unable to take the gas.

²I use the term "spot market" to denote the existence of an institutional mechanism which allows buyers to purchase and sellers to sell at a prevailing price and without prior notice or contract. No single buyer or seller dominates this market. As such, a spot market can be an alternative to long-term contracts or vertical integration.

industry). This paper will be primarily concerned with vertical integration by pipelines into production and long-term contract arrangements between pipelines and producers.

Central to the explanation proposed here of these trends in vertical market arrangements is the allocation of risk across the tiers of the gas industry (the term "risk" will be defined more precisely later). The thesis of this paper has three basic components:

1. Wellhead price decontrol increases the underlying riskiness of the gas business. Under the existing relationships between regulated interstate pipelines and distribution companies a portion of these risks get immediately transferred to the pipeline segment of the industry. Because the pipeline regulatory authority responds imperfectly to changes in risk, interstate pipelines have an incentive to shift these risks further upstream to the unregulated producers. Wellhead price decontrol may increase risk in the unregulated intrastate market but the intrastate pipelines should have no comparable regulatory incentive to shift risk toward producers.

2. Particular vertical market arrangements can conceivably be used by the regulated pipelines to alter the allocation of risk among the industry tiers. In particular, decreased take-or-pay requirements and vertical integration can serve to shift risks toward independent producers.

3. This effect can be investigated empirically using the risk measures developed in financial economic theory. Partial wellhead price decontrol in 1978 and the behavior of the unregulated intrastate pipelines can be used to test for this risk-shifting behavior by the interstate pipelines. The results of this investigation support the risk-shifting explanation of the observed changes in vertical market

arrangements.

The prospect of complete wellhead price decontrol has led regulatory policymakers to begin to question whether the current form of interstate pipeline regulation by the Federal Energy Regulatory Commission (FERC) is appropriate to the new circumstances. Proposals have been put forward which range from changing the structure of the existing FERC pipeline tariff, to making gas pipelines common carriers, to deregulating interstate gas pipelines.

While it is not the purpose of this paper to provide a complete analysis of the merits of each of these regulatory alternatives, it does analyze the changing nature of vertical market arrangements in the gas industry in the context of the current regulatory system. In the consideration of any regulatory alternative for the gas industry, the behavior of pipelines under the current regulatory system should be understood.

The remainder of this paper is divided into five parts. In Part II the importance of vertical market arrangements in the evolution of the gas industry will be discussed and some evidence of recent changes will be presented. Part III reviews the models in the industrial organization literature that might help explain these arrangements. In Part IV the conceptual connections between vertical market arrangements and the allocation of risk under regulation are presented. A resulting proposition with respect to the gas industry is analyzed empirically in Part V by looking for changes in the allocation of risk that might have been occasioned by the partial decontrol of wellhead prices in 1978. Finally, the implications of these results are considered in light of FERC pipeline regulation.

II. VERTICAL MARKET ARRANGEMENTS IN THE GAS PIPELINE INDUSTRY

Throughout the history of the gas pipeline industry different vertical market arrangements have been an important motivating force for, and result of, federal and state regulation.³ Prior to the Natural Gas Act of 1938 (which imposed federal regulation on interstate pipelines), state-regulated gas producers, gas manufacturers and distributors were integrating into interstate pipeline operations. In the Appalachian region particularly, producing-state governments were trying to protect their indigenous gas-using industries by controlling gas allocation or by regulating prices. Since interstate pipeline operation fell outside state jurisdiction, the integrated companies were able to retain the economic rents that were the target of state regulation. Federal regulation was designed to fill this regulatory void, and consequently, what might have become a fully-integrated system from field to burner tip was transformed into the three-tiered system we observe today, where each tier is under a separate regulatory authority or set of procedures.

With federal regulation of pipelines in 1938, and particularly after the imposition of wellhead price controls in 1954, substantial vertical integration gave way to relationships between producers and pipelines based on long-term contracts with high take-or-pay requirements. In fact, most pipeline capital investments during the post-war growth period were financed conditionally on the signing of long-term supply and service

³For a more detailed history of gas pipeline regulation, see Carpenter, Wright and Jacoby, "A Preliminary Analysis of Gas Pipeline Regulation After Decontrol", MIT Energy Lab, mimeo draft, 1982.

agreements at both ends of the pipeline.⁴ The signing of these contracts was an integral part of the FPC pipeline certification process. Many of the long-term contracts still operating in the gas industry were signed in the mid-to-late 1960s and will be reaching the end of their terms in the mid-to-late 1980s.

The 1938 Natural Gas Act and the Phillips decision regulating wellhead prices did not apply to the intrastate market. Intrastate pipelines are generally not regulated and have enjoyed access to gas not subject to wellhead price controls. While the intrastate market is not a pure example of the operation of an unregulated system, a comparison of the interstate and intrastate pipeline industries will prove useful below.

Since the partial decontrol of wellhead prices resulting from the NGPA of 1978, there are some indications that the nature of the long-term contracts and vertical market structure in the industry is changing. It is not possible to precisely document these changes, since pipeline companies are not required to file reports to FERC on all of their outstanding contracts. But some anecdotal evidence is available from a recently completed sample survey of pipeline-producer contracts by the DOE Energy Information Administration (EIA).⁵

First, the average percentage take-or-pay quantity requirement appears to be decreasing, and the take-or-pay requirements are relatively low for the NGPA Section 107 "deep gas" which was deregulated in 1978.

⁴For a brief discussion of the importance of these contracts, see Morris A. Adelman, The Supply and Price of Natural Gas, Blackwell, Oxford, 1962, pp.66-75.

⁵U.S. Department of Energy, Energy Information Administration, Natural Gas Producer/Purchaser Contracts and their Potential Impacts on the Natural Gas Market, DOE/EIA-0330, June 1982.

As Table 1 indicates, the average take requirement in the EIA sample reached 94 percent of well deliverability between 1973 and April 1977 but had declined to 79 percent by 1980. In terms of gas type, take requirements for NGPA Section 107 gas were the lowest for all types across all years in the EIA sample, at 75.8 percent. Intrastate contracts (NGPA Sections 105/106b) in the sample also showed relatively low take requirements of 75.9 percent of well deliverability.

A second indicator of contract quantity flexibility is buyer-protection or "market-out" clauses. These clauses permit the buyer to opt out of a contract if the gas is deemed unsellable at the contract price. According to the EIA sample survey, the percentage (by volume) of contracts with market-outs has increased dramatically from 3.6 percent in contracts of vintage 1977-1978 to 45.3 percent in contracts of vintage 1978-1980. For Section 107 deregulated gas, 41.8 percent of the EIA sample interstate contracts had market-out clauses, while 86.5 percent of the intrastate sample had market-out provisions.

Finally, the length of contract term has been decreasing. The EIA sample survey indicates that 85.8 percent of pre-1973 vintage contracts were for 20 or more years. Of the contracts signed in 1980 only 7.3 percent were for 20 or more years, while 35.2 percent had terms of less than 10 years.⁶

In addition to these changes in contract terms, many observers of the gas industry see a trend toward vertical integration by pipeline

⁶U.S. DOE/EIA, op.cit., pp.30,33,43.

Table 1

Summary of Take-or-Pay Provisions
by NGPA Section and Vintage^a

NGPA Section	Weighted Average Percent Take Req't
102 Onshore	87.2 (0.03)
102 Offshore	90.4 (0.01)
103	80.1 (0.02)
107	75.8 (0.04)
108	97.8 (0.02)
105/106b	75.9 (0.09)
104/106a	92.0 (NA)
Vintage ^b	
Pre-1973	78.1 (0.08)
1973-April 20, 1977	94.0 (0.03)
April 20, 1977-Nov. 8, 1978	88.0 (0.02)
Nov. 9, 1978- 1979	86.8 (0.02)
1980	79.0 (0.02)

^aCoefficients of variation are in parenthesis.

^bData by vintage do not include Section 104 and 106a gas.

Source: DOE Energy Information Administration, op.cit., p.41.

companies into production.⁷ Table 2 indicates the percent of total reserves which are owned by the major interstate pipelines as opposed to being under contract. This figure increased from 10.8 percent in 1977 to 12.6 percent in 1979.

In summary, the available evidence indicates that changes in vertical market arrangements are taking place in the gas industry in the form of decreased take requirements in long-term contracts and increased backward integration by pipelines into production. These changes seem to coincide with the partial decontrol of wellhead prices begun in 1978. In the next section the industrial organization literature is examined for alternative explanations of the kinds of vertical market arrangements observed in the gas industry.

⁷See for example U.S. Congressional Research Service, Natural Gas Regulation Study, prepared for the U.S. House of Representatives, Committee on Energy and Commerce, Committee Print 97-GG, July 1982, p.2.

Table 2

Natural Gas Reserves Owned by Pipelines
(Own reserves as a percent of total
contracted reserves)

	<u>Major Companies</u> [*]
1975	10.4 percent
1976	10.6
1977	10.8
1978	11.1
1979	12.6
1980	12.4

^{*}Defined as having over 900 billion cubic feet of reserves at
the time of initial FERC Form 15 filing.

Source: U.S. DOE/EIA, Gas Supplies of Interstate Natural Gas Pipeline
Companies, derived from FERC/FPC Form 15 filings, DOE/EIA-0167

III. VERTICAL MARKET ARRANGEMENTS IN THE INDUSTRIAL ORGANIZATION LITERATURE

If one divides the existing industrial organization literature based on the suggested sources of or motivations for vertical market arrangements, then there are three bodies of opinion.

The first says that vertical integration is linked to the exercise of monopoly power. In some cases it is said to result from the upstream exercise of monopoly power (Schmalensee, 1973). In this model, monopolist firms will vertically (forward) integrate when the downstream industry uses the monopolist's input in variable proportions with other inputs. Since downstream firms will tend to substitute away from the monopolist's input, integration by the monopolist will force the efficient use of its input. A parallel model (Perry, 1978) suggests that monopsonists downstream may backward integrate in order to eliminate the efficiency losses resulting from their monopsony behavior.

Neither of these models attempts to distinguish vertical integration from long-term contracts. There is no strong reason why a contract (such as a tying contract) could not be written to eliminate the inefficient substitution effects. In any case, this strand of the literature does not directly apply to the gas pipeline industry since there is no evidence in this industry of sustained market power either on the part of

producers (as monopolists) or pipelines (as monopsonists).⁸

Furthermore, pipelines are merely transportation intermediaries for gas. Gas is not an input to a pipeline's production function in the sense contemplated by these models.

The second branch of the literature is developed primarily by the work of Coase (1937) and more directly, Williamson (1975). In markets characterized by uncertainty and small numbers of firms, vertical integration is a means of avoiding "opportunistic" behavior (in the language of Williamson).⁹ In this view, long-term contracts are a possible alternative to vertical integration, but they entail prohibitive transaction costs both in the specification of the contingent states of the world and in the enforcement of the contract provisions. So the primary thrust of this literature is to attempt to distinguish between long-term contracts and vertical integration on the basis of transaction costs. This topic will come up again later.

The final branch of the literature is more directly related to our interests. This is the model of vertical integration as a means of "supply assurance" developed by Carlton (1979). The situation he has in mind is a market composed of retailers (which he calls Stage 1 firms --

⁸For the definitive study of market power at the field, see Paul MacAvoy, Price Formation in Natural Gas Fields, Yale U. Press, New Haven, 1962.

⁹To Williamson, the concept of "opportunism" involves self-interest seeking by individuals "with guile" in small-numbers situations. He would argue that even though a market is competitive, once a long-term contract is signed between two individuals a bilateral monopoly situation is created and "opportunistic" behavior can result in one party's gain at the other's expense -- hence the need for enforcement provisions and litigation procedures in long-term contracts. See Benjamin Klein, et.al., "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process", Journal of Law and Economics, Vol. 21, 1978, p.247.

pipelines in our case), and wholesalers (Stage 2 firms -- producers in our case). Each level of the market faces random demand. The price from the wholesaler, P_w , is fixed and independent of quantity. Own production of the input is characterized by constant returns to scale at unit cost C . The retailers have the choice of backward integrating or buying from wholesalers. Carlton's model predicts that the retailers will backward integrate if $[1-\text{prob}(0)] \cdot P_w > C$. That is, integration is desirable if the cost of producing one unit of the input internally, C , is less than the expected savings from having to go to the wholesaler for the one unit, where $[1-\text{prob}(0)]$ is the probability that at least one customer frequents the retailer.

In other words, if the Stage 1 firm produces the input itself, then the firm assures itself of having the necessary input to make a profitable sale, if demand should materialize. Offsetting this saving is the potential risk that the input will be produced at cost C , but will not be used because of insufficient demand.¹⁰

This model has one of the features we are looking for, uncertain demand. Vertical integration by the stage 1 firms shifts the demand uncertainty to the stage 2 firms. Carlton recognizes this result:¹¹

(A main) feature involves the differential risk that a vertically integrated firm can impose between the use of its own inputs and the inputs of a factor market firm. Because a firm will always choose to use its own inputs first¹², there is always a higher probability that a firm will use a unit of its own input than a unit of input that factor market firms hold.

¹⁰Dennis Carlton, "Vertical Integration in Competitive Markets Under Uncertainty", Journal of Industrial Economics, XXVII No.3, March 1979, p. 196.

¹¹Ibid., p.205.

¹²Presumably this is because $P_w > C$.

Other features make the model not directly applicable to the gas industry. First, in the gas pipeline case there is no necessary cost advantage to in-house production, as is necessary for Carlton's stage 1 firm to see any advantage in backward integration. Second, long-term contracts and vertical integration achieve the same result in the Carlton model. In his model it would be paradoxical, then, to observe more vertical integration at the same time that a trend toward more flexible and shorter-term contracts is observed. Finally, Carlton's model was not designed for a world of rate-of-return regulation.

In short, the industrial organization literature does not offer a convincing explanation for the variety of changes in vertical market arrangements we are now observing in the gas industry. Moreover, little thought has been given to the relationship between rate-of-return regulation and the incentives for regulated firms to enter into certain types of vertical market arrangements. The next section gives a conceptual basis for this connection.

IV. SYSTEMATIC RISK, VERTICAL MARKET ARRANGEMENTS AND REGULATION

A. Systematic Risk, Cash Flows and Vertical Market Arrangements

The central proposition in this paper is that regulated gas pipelines will enter into particular vertical market arrangements as a means of altering the underlying riskiness of their business. The risks we are interested in are the factors that create volatility in the returns on a firm's assets. Since all investors can invest in a well-diversified portfolio (e.g., a mutual fund or, most broadly, the "market" as a whole), investors will only be concerned with firm-specific variance that is not diversifiable -- in other words, variance that is correlated with the market as a whole. This variance is commonly referred to as "systematic" or "non-diversifiable" risk. Unsystematic or "unique" risk, in contrast, is not correlated with the general market and hence is readily diversifiable. If capital markets are in equilibrium, securities will be priced to provide a return proportional to the systematic risk, with no adjustment for the unsystematic sources of variance.

Under the assumptions of this capital asset pricing model (CAPM) of finance theory¹³, the firm's systematic or non-diversifiable risk is defined as:¹⁴

$$\beta_{\text{asset}} = \frac{\text{cov}(r, r_m)}{\sigma_m^2}$$

¹³For a more detailed discussion of the implications of CAPM see Richard Brealey and Stewart Myers, Principles of Corporate Finance, McGraw Hill, New York, 1981. Two of the articles in which this theory was developed are W.F. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk", Journal of Finance, 19, Sep. 1964, pp.425-442, and J. Lintner, "The Valuation of Risky Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets", Review of Economics and Statistics, 47, Feb. 1965, pp.13-37.

¹⁴For the moment assume we have an all-equity financed firm.

where r is the firm's market return, r_m is the return on the market as a whole and σ_m^2 is the variance of the market return.

In order to relate changes in vertical market arrangements to this measure of systematic risk, we need to relate the firm's return, r , to the set of factors which these arrangements can affect, namely, the firm's cash flows.

At any time t , the firm's market value, or $PV_t(CF)$, is the present value of the firm's expected future cash flows, CF_t :

$$PV_t(CF) = \sum_{i=t}^{\infty} CF_i / (1+\rho)^i$$

where ρ is a risk-adjusted discount rate.

The firm's return in any period is just the percent change in $PV_t(CF)$. Thus,

$$r_t = [PV_t(CF) / PV_{t-1}(CF)] - 1$$

For our purposes here we can divide the firm's cash flows into revenues, R , variable costs, VC , fixed costs, FC , and take-or-pay payments, T .¹⁵

Thus,

$$PV_t(CF) = PV_t(R) - PV_t(VC) - PV_t(FC) - PV_t(T)$$

and

$$r_t = \frac{[PV_t(R) - PV_t(VC) - PV_t(FC) - PV_t(T)]}{PV_{t-1}(CF)} - 1$$

Substituting this expression into the definition of the risk measure,

¹⁵We have separated take-or-pay payments from costs. These are the payments made by pipelines to producers for gas which they had contracted for but could not take. A technicality which should be noted is that gas pipeline take-or-pay contracts with producers have "make-up" provisions which allow pipelines to take additional gas for which they previously paid but did not take. FERC imposes a minimum make-up period of five years, after which the pipeline loses any make-up opportunity. FERC will also allow the interest cost of this "paid-for-but-not-taken" gas to be put in rate base during the make-up period. These provisions serve to lessen the present value of expected future take payments, but do not drive it to zero.

β_{asset} , and recognizing the additivity of covariances yields:

$$\beta_{\text{asset}} = \beta_{\text{rev}} \cdot \left[\frac{PV_{t-1}(R)}{PV_{t-1}(CF)} \right] - \beta_{\text{vc}} \cdot \left[\frac{PV_{t-1}(VC)}{PV_{t-1}(CF)} \right] - \beta_{\text{fc}} \cdot \left[\frac{PV_{t-1}(FC)}{PV_{t-1}(CF)} \right] - \beta_T \cdot \left[\frac{PV_{t-1}(T)}{PV_{t-1}(CF)} \right]$$

where, for example, $\beta_{\text{rev}} = \text{cov} \left[\frac{PV_t(R)}{PV_{t-1}(R)} - 1, r_m \right]$

The firm's systematic risk or "beta" is thus defined as a weighted sum of cash flow betas, where the weights are the present value proportions of the firm's market value contributed by each of the components of the firm's cash flow.

What are the characteristics of this relationship for gas pipeline companies and how do various vertical market arrangements affect it? First, we can expect β_{rev} and β_{vc} to be positive. Changes in pipeline revenues and purchased gas costs can be expected to be positively correlated with general economic activity (but less so under wellhead price controls). β_{fc} will be approximately equal to zero, and β_T will be probably negative (zero at most) since economic downturns should be correlated positively with the size of pipeline take payments, particularly with those that a pipeline cannot recover through "make-up" provisions (c.f. footnote 15).

The fact that $PV_t(R) > PV_t(VC)$, coupled with $\beta_{\text{fc}} \approx 0$, leads to an effect known as operating leverage.¹⁶ Operating leverage refers to the ratio of fixed to variable operating costs. An increase in operating leverage (holding total costs constant) will lead to a decrease in $PV(VC)$

¹⁶Baruch Lev has empirically estimated this effect and finds some support for it in the electric utility and steel industries. See Baruch Lev, "On the Association Between Operating Leverage and Risk", Journal of Financial and Quantitative Analysis, September 1974, pp.627-641.

and thus to an increase in the firm's systematic risk, β_{asset} .

Different vertical market arrangements affect the last term in the risk/cash-flow relationship, $PV(T)$, the present value of expected future take payments. Contracts signed with lower take requirements (holding total costs constant) will lead to lower expected future take payments and will decrease β_{asset} since $\beta_T < 0$. Note that part of this affect is analogous to operating leverage. If total costs are held constant, a decrease in take payments will imply an increase in variable costs relative to fixed costs, which also serves to decrease β_{asset} .^{17,18}

We have seen how long-term, take-or-pay contracts affect the systematic risk of the firm. But what about vertical integration? Recall from Section III that long-term contracts and vertical integration are traditionally viewed as alternative means of accomplishing the same objective. Transaction costs have been proposed as the only convincing distinction between them.¹⁹ However, in the risk-shifting sense

¹⁷There is a slight complication here in that one would expect a pipeline to offer a lower gas price to producers for a contract with a lower take-or-pay requirement (so total costs will not really be constant). But since pipeline purchased gas costs are fully passed-through under regulation, this price decrease will affect both revenues and costs. Whether or not the price effect on revenues and costs is offsetting depends on demand elasticities among other things. I am treating this price complication as a second-order effect.

¹⁸It has also been suggested that a long-term take-or-pay contract can be considered a put option written by the pipeline and sold to the producer. This suggests a possible way to value these contracts which accounts for the value of expected take payments. Unfortunately, gas pipeline contracts rarely come in pure take-or-pay form. Other clauses such as "market-outs" (automatic contract renegotiation if the gas is unsellable at the contract price) and price renegotiation provisions complicate any attempt to directly estimate the value of the take-or-pay feature of the contract.

¹⁹For the advanced form of the transaction cost approach, see Oliver Williamson, "Transaction-cost Economics: The Governance of Contractual Relations," Journal of Law and Economics, October 1979, pp.233-261.

described here, long-term contracts and vertical integration have different effects. The replacement by a pipeline of a long-term gas supply contract with the purchase of its own reserves serves to decrease the present value of expected take payments and increase expected variable costs. In this sense, vertical integration is analogous to signing a long-term contract with one's own firm at a very low take requirement.^{20,21}

B. Risk and Rate-of-Return Regulation

The relationship between take-or-pay contracts, vertical integration and systematic risk suggests that a firm could undertake a conscious strategy to alter its underlying business risk. But under what conditions would a firm have an incentive to do this? Efficient markets will reward firms for bearing systematic risk. Thus, in a perfectly competitive, frictionless market there would be nothing gained by reducing systematic risk because both the achieved and required returns

²⁰The leverage part of the argument requires that the fixed costs of gas production be small relative to total costs, which is quite true, and that there be no cost advantage or disadvantage to own production.

²¹An assumption is implicit here concerning the market for gas reserves. If this market is perfectly competitive and efficient with respect to market information, then any risk-shifting benefits a pipeline might enjoy through vertical integration would be capitalized into the price paid for the production reserves. Any incentive to vertically integrate would thus be negated. To get around this, we must assume that all of these rents are not bid away by pipelines competing for the same reserves. This assumption is plausible since the equilibrium will include some combination of vertical integration and independent ownership. Thus, the market for reserves will be "thin" in some respects and independent owners are likely to accept less than full rent-capitalization in the price of the reserves they sell. Note that an assumption of this sort is required for any theory of vertical integration, in which the integration involves the acquisition of real assets.

would correspondingly drop, leaving the firm's market value unchanged. Such is not the case, however, in the regulatory environment in which gas pipeline companies operate. While the capital markets will respond efficiently to adjust required returns, allowed and achieved returns may lag.

The landmark Supreme Court cases Bluefield Water Works (1923)²² and Hope Natural Gas (1949)²³ established as the guiding principle of public utility regulation that:²⁴

the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

While this standard is vague enough to encompass any risk/return concept, including one consistent with the implications of efficient markets, it has traditionally been interpreted to mean that utilities should earn returns on the book value of assets comparable to the market returns of other firms of comparable risk -- hence the label "comparable earnings standard". This traditional interpretation has many serious drawbacks from a theoretical point of view which are well-detailed elsewhere.²⁵

²²Bluefield Water Works and Improvement Co. vs. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

²³Federal Power Commission et.al. vs. Hope Natural Gas Co., 320 U.S. 591 (1949).

²⁴Ibid., at 603.

²⁵For a comprehensive discussion of the limitations of the comparable earnings standard and alternatives to it, see Stewart Myers, "The Application of Finance Theory to Public Utility Rate Cases," Bell Journal of Economics and Management Science, Spring 1972, pp.58-97.

For our purposes here the consequences of these limitations is that the regulatory process is not set up to consistently balance allowed returns with the firms' systematic risk. Furthermore, the process is not rapidly adaptive. As a company's return exceeds or falls below the "comparable earnings" allowed return, an adjustment may not be made to bring required revenues back into line for several years.²⁶ Under these regulatory conditions a profit maximizing firm will have an incentive to reduce its systematic risk.²⁷

In the next section the story outlined in the introduction, concerning the effect of wellhead price decontrol on the incentives for interstate pipelines to shift risks toward producers, is described in more detail and an empirical analysis of the effect is performed.

²⁶The so-called "settlement method" or "trackers" method employed by FERC during the period of gas curtailments is an exception. But this was a special circumstance where it was necessary to remedy the down-side revenue distortions caused by volume curtailments.

²⁷Regulation seems to be able to adapt more rapidly to changes in some types of risks than others. For example, FERC seems to respond quickly to changes in financial risk due to changes in a firm's capital structure. Certainly a major factor explaining this is the ease with which these risk-shifting effects can be measured. Debt in the capital structure is relatively easy to determine.

V. GAS PIPELINES AND WELLHEAD PRICE DECONTROL

This section uses the preceding conceptual argument to explore the effects of wellhead price decontrol on the incentives for pipelines to shift risks by altering their vertical market arrangements. The event of partial decontrol of wellhead prices in 1978 and a group of unregulated intrastate pipelines will be used to look for the effects of the risk-shifting proposition. Note that this parallel existence of variously regulated firms is an unusually powerful natural experiment for analysis of this kind.

A. Wellhead Price Controls in the Interstate Market

During the period of wellhead price controls the gas industry evolved into a fairly stable equilibrium. Prices changed only rarely and excess demand prevented variations in economic activity from influencing volumes sold. Thus, systematic risk on revenues in the gas industry was low. Shortages persisted throughout the early 1970s, but the risk of shortages or curtailments was not systematic. That is, these events were not correlated with the state of the economy as a whole, so investors could diversify away this risk. The interstate pipelines were willing to sign contracts with high take-or-pay requirements. There were several reasons for this behavior. First, because prices and quantities were not fluctuating with economic conditions, there was not a lot of revenue risk for the expected take payments to lever (i.e., β_{rev} and β_{vc} were low and β_T was close to zero). What was of concern to pipelines was the danger of experiencing the effects of volume shortages and curtailments. This was a consequence of the way fixed costs in the pipeline's rate base

were recovered under standard regulatory procedures,²⁷ and had little to do with the allocation of systematic risk. This concern for volume led them to desire contracts with high take-or-pay requirements in times of regulatory curtailment, but this concern is not sufficient to explain why these contracts are currently undesirable or why vertical integration is currently desirable as an alternative. Second, even if there was systematic revenue risk to bear, producers would be unwilling to take on added risks because the market could not reward them for bearing these risks - their field prices were controlled. Alternatively, one can think of a contract with a high take-or-pay requirement as a means of non-price compensation of producers by pipelines while gas was under price controls.

B. Wellhead Price Decontrol in the Interstate Market

After the decontrol of wellhead prices two things will happen. First, interstate pipeline cash flows will become systematically more risky as excess demand is eliminated and the demand for gas (particularly industrial demand) fluctuates in response to general economic conditions.²⁸ Second, the elimination of wellhead price controls means that the market will now be able to reward independent producers for taking on systematic risk. Under the assumption of no change in FERC

²⁷Because pipelines' fixed costs in rate base are recovered on the basis of a test-year volume, curtailments and shortages would directly influence their ability to cover their costs.

²⁸I am making an implicit assumption here about the relationship between pipelines and state-regulated distribution companies. In particular, I am assuming that pipelines are unable to shift revenue risks toward the distribution companies. This is probably not too heroic, since the regulatory avenues open to distribution companies to relax their contract requirements with pipelines are many and varied. Many state regulatory bodies are already challenging pipelines' automatic purchased gas adjustments on behalf of their distribution companies.

pipeline regulation, on the basis of our hypothesis we would expect to see the shifting of systematic risk by pipelines to producers in two ways. By negotiating lower take-or-pay requirements in their new contracts, pipelines can decrease the present value of their expected take payments and thus their systematic risk. By backward integrating the pipelines can also decrease their take payments and increase their variable costs as a fraction of total costs -- reducing their systematic risk.

In terms of our risk/cash-flow relationship we can summarize these effects of decontrol on interstate pipelines as follows. (The solid arrows indicate the effects of decontrol and the dashed arrows indicate the compensating effects of changes in vertical market arrangements. The W 's stand for the present value weights of the cash flow components).

$$\beta_{\text{asset}} = \beta_{\text{rev}} \cdot W_{\text{rev}} - \beta_{\text{vc}} \cdot W_{\text{vc}} - \beta_{\text{fc}} \cdot W_{\text{fc}} - \beta_{\text{T}} \cdot W_{\text{T}}$$

sign	(+)	(+)	(+)	(≈ 0)	(-)
effect	\uparrow \downarrow	\uparrow	\uparrow \uparrow		\downarrow $\uparrow\downarrow$

Note that all of the decontrol effects work to increase β_{asset} .

In the intrastate market we should not observe any compensating effects, since no fundamental changes in risk-bearing incentives have occurred in this market, despite the fact that we should observe increases in β_{rev} and β_{vc} (and thus β_{asset})²⁹, as summarized

²⁹This expectation of an increase in revenue risk in the intrastate market is debatable. As mentioned in section one, the intrastates cannot be considered an example of a pure unregulated system. Wellhead price controls caused supplies of gas to be diverted to the intrastate market from the interstate market. Prices were higher in the intrastate market but, because of the supply influx, they were still below the price of competitive fuels. Wellhead decontrol will shift the intrastate gas supply curve to the left which will lead to substitution away from gas in the industrial and utility markets. What is uncertain here is whether the new long-run equilibrium in the intrastate market will be characterized by more or less systematic revenue risk.

below.

$$\beta_{\text{asset}} = \beta_{\text{rev}} W_{\text{rev}} - \beta_{\text{vc}} W_{\text{vc}} - \beta_{\text{fc}} W_{\text{fc}} - \beta_{\text{T}} W_{\text{T}}$$

sign	(+)	(+)	(+)	(~0)	(-)
effect	↑	↑	↑		↓

C. Empirical Analysis

The proposition to be examined is that wellhead price decontrol allows pipelines to shift systematic risks to producers through changes in their vertical market arrangements and that this effect will be observed in the interstate and not in the intrastate market.

A direct analysis of this proposition would require that we try to estimate the present value of future take payments, $PV(T)$, and the take-or-pay risk, β_T , in both markets and compare them before and after the partial decontrol event in 1978. For a number of reasons this is not possible, not the least of which is the absence of available information on the details of long-term contracts in the intrastate market. However, the two charts presented at the end of the last section suggest an indirect test of this proposition, for which data in both markets is readily available. That is, we can compare the pipelines' revenue risk, β_{rev} , with their asset risk, β_{asset} , before and after the partial decontrol of wellhead prices. As the dashed arrows indicated, if this risk-shifting behavior is at work, we should expect to see increases in revenue risk not fully-reflected in β_{asset} in the interstate market, while they should be fully-reflected in β_{asset} in the intrastate market.

Despite the indirect nature of this analysis, it is appealing for several reasons. First, this industry features a potentially useful experiment of the effects of regulation due to the existence of a comparison group of unregulated firms. Second, financial data for those intrastate pipelines that are publicly traded appear to be the only consistently-collected time-series available for the intrastate market. It is worth exploring whether regulatory policy questions can be studied using the relationship between market-determined and accounting-based data³⁰, particularly in this industry that otherwise suffers so badly from polluted data.

D. Data

The gas pipeline industry is not homogeneous. Most pipeline companies are subsidiaries or divisions of large energy companies or holding companies. Since these non-pipeline business activities may differentially affect the firms' revenues and market values they could seriously distort the analysis. To minimize the effects of extraneous business activities on the beta calculations, the pipeline companies chosen were those whose revenues from pipeline operations were at least 65 percent of total company operating revenues in 1980.³¹

The limitations of the data from the CRSP and COMPUSTAT series posed a second problem. The companies had to be publicly traded, and quarterly revenue data had to be available from 1972.IV through 1981.IV.

³⁰For an excellent summary of the potential of and practical problems with these techniques see, G. William Schwert, "Using Financial Data to Measure Effects of Regulation", Journal of Law and Economics, April 1981, pp.121-158.

³¹Of some comfort here is an unpublished study of the gas transmission industry by Gerald Pogue. His calculations of accounting-based betas do not differ substantially between total company and pipeline-only operations.

The sample of firms which passed these tests are:

<u>Interstate</u>	<u>Intrastate</u>
American Natural Resources	Enserch Corp.
Columbia Gas System	Houston Natural Gas Corp.
Equitable Gas Co.	ONEOK Inc.
Mountain Fuel Supply Co.	Pioneer Corp. - Texas
Panhandle Eastern Co.	Texas Oil and Gas Corp.
Peoples Energy Corp.	

All calculations were performed with respect to these two portfolios in order to minimize the inevitable noise associated with individual company betas, and to further minimize the effects of non-pipeline business activities.

E. Results

The estimation of asset betas is a two-step process. First, equity betas are estimated from stock market data. They are then "unlevered" to remove the effects of financial leverage (debt in the capital structure) on equity risk. This gives us our asset beta measure.

1. Equity Betas

Equity betas (in which the effects of the firms' capital structure have not yet been removed) were calculated for each portfolio by regressing the value-weighted monthly pipeline portfolio security returns from CRSP on the monthly value-weighted composite New York Stock Exchange (NYSE) returns. This so-called "market model" is:

$$r_j = \alpha + \beta_{eq} r_m + \epsilon$$

where r_j = monthly return on portfolio j ,

r_m = monthly return on value-weighted NYSE.

Table 3 presents the results. At first glance the estimated coefficients, β_{eq} , appear to have increased substantially after 1978 for both portfolios -- from .72 to .97 for the interstates and from 1.02 to 1.36 for the intrastates. But a Chow test of the significance of the

Table 3
Equity Betas

<u>Interstate Portfolio</u> (standard errors in parenthesis)				
	α	β_{eq}	SSR	R^2
12/1972 - 3/1978* (64 observations)	.008 (.005)	.717 (.093)	.086	.48
4/1978 - 12/1981 (45 observations)	.002 (.006)	.973 (.125)	.064	.58
12/1972 - 12/1981 (109 observations)	.006 (.004)	.807 (.074)	.155	.52
<u>Intrastate Portfolio</u>				
	α	β_{eq}	SSR	R^2
12/1972 - 3/1978 (64 observations)	.008 (.006)	1.02 (.125)	.158	.51
4/1978 - 12/1981 (45 observations)	.019 (.008)	1.36 (.166)	.114	.60
12/1972 - 12/1981 (109 observations)	.014 (.005)	1.16 (.101)	.283	.55

*The choice of 3/1978 as the break-point for the "event" of decontrol was made to reflect the date of passage of the Natural Gas Policy Act of 1978 and to correspond with the break-point in the quarterly revenue data used later. The choice of break-point is always controversial in event studies of this kind due to the ability of the market and firms to anticipate legislative and regulatory changes. In this case an argument can be made that the NGPA was not a legislative act that could be easily anticipated. In fact, the NGPA was constructed almost totally in a Congressional conference committee as a compromise between two radically different bills, one of which called for added price controls.

interperiod differences yields $F(2/105) = 1.75$ for the interstate portfolio and $F(2/105) = 2.12$ for the intrastate portfolio, neither of which indicates significance at the .05 level.

Our suspicions that the equity of interstate firms is less systematically risky than that of the intrastates are confirmed but only for the 1978-1981 time period. A Chow test of the significance of the inter-portfolio differences yields $F(2/124) = 1.78$ for the 1973 through 1977 period and $F(2/86) = 4.59$ for the 1978 through 1981 period, the latter indicating significance at the .05 level.

Thus we find that the intrastate portfolio has become systematically more risky relative to the interstates after partial decontrol in 1978 as would be expected by the risk-shifting proposition. But recall that the measure here was equity risk not asset risk.

2. Financial Leverage, Asset Betas

To what extent do differences in capital structure account for the differences in systematic risk as measured above by equity betas? The equation used to "unlever" the equity betas is one developed by Robert Hamada.³²

$$\beta_{\text{asset}} = \frac{\beta_{\text{eq}}}{[1 + (1 - T_c)(D/E)]}$$

where T_c = the marginal corporate tax rate (48 percent),
 D = the market value of the firms' long term debt,
 E = the market value of equity.

The difficult term here is D , the market value of long-term debt, since most firms have a variety of debt vintages at various market prices. To

³²Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," Journal of Finance, XXIV, March 1969, pp.13-31.

estimate this value for the two portfolios in each time period a method developed by Gerald Pogue was employed:³³

$$\begin{aligned} \text{Market Value of} \\ \text{Long Term Debt} \end{aligned} = \sum_{t=0}^N \frac{\text{Long Term Interest Paid}}{(1 + R)^t} + \frac{\text{Long Term Debt Book Value}}{(1 + R)^N}$$

where

R = the capitalization rate (assumed equal to Moody A industrial bond index rate)

N = average number of years to maturity for long term corporate debt (assumed to be 11 years on average)

Calculations were made for each year in the period of study and were then averaged to obtain estimated D/E ratios for each sample period. The results of these calculations are presented in Table 4. As indicated by the debt/equity ratios, the interstate pipeline portfolio is substantially more financially leveraged than the intrastate portfolio, both before and after decontrol. Moreover, both groups' leverage decreased after 1978, the intrastate D/E ratio falling to .28, the interstate ratio to .90. Thus, instead of offsetting the difference in risk between the inter and intrastate portfolios found above for the post-1978 period, the elimination of financial leverage effects serve to exacerbate the differences in underlying risk, as seen at the bottom of Table 4. Both groups have increased asset betas, but the increase is borne more heavily by the intrastate firms.

³³Gerald S. Pogue, Testimony before the U.S. Federal Energy Regulatory Commission in re Williams Pipeline Company, docket Nos. OR79-1, et.al, 1979, p.70.

Table 4
Financial Leverage Calculations

Debt/Equity	<u>1972-1977</u>	<u>1978-1981</u>
Interstate	1.18	.90
Intrastate	.53	.28
β_{eq}		
Interstate	.72	←-- n --→ .97
	↑ n ↓	↑ s ↓
Intrastate	1.02	←-- n --→ 1.36
β_{asset}		
Interstate	.45	.66
Intrastate	.80	1.19

n indicates differences not statistically significant

s indicates differences statistically significant

3. Revenue Betas

We have examined the effects of financial leverage and have found that it does not explain the significantly increased riskiness of the intrastate portfolio relative to the interstate portfolio after 1978. Does a relative increase in revenue risk account for the difference? If not, then there may be reason to believe that a change in vertical market arrangements is at work.

To answer this question, revenue betas were estimated using quarterly revenue data for the two portfolios from 1972.IV through 1981.IV and the quarterly return on the value-weighted NYSE. The estimation of relationships between accounting-based data and market-determined data presents immediate difficulties. First, and perhaps foremost, an efficient and forward-looking capital market can be expected to anticipate effects which will appear in future accounting data. Furthermore, for the interstates, regulatory lag will result in revenue changes which will be allowed usually six months³⁴ after the effects are "recognized" by the market and felt by the firms. Second, quarterly accounting data tend to be dominated by seasonality. In principle this is not a problem since the market return does not have substantial seasonal characteristics. But the seasonal variance may be so large as to swamp the market relationship being estimated. The ability to deal with both of these problems through the use of lag structures and seasonal adjustment is constrained by what is initially an already limited number of degrees of freedom. In this case zero, one and two period lags in the market return - revenue relationship were

³⁴Pipelines are allowed by FERC to make purchased gas adjustment (PGA) filings every six months.

estimated³⁵. (There is some logic in a two-period or six month lag in the interstate market due to the regulatory process.) Seasonal adjustment did not materially alter the results which are presented in Table 5.

As indicated, all of the estimated revenue betas are indistinguishable from zero with the exception of the post-1978 two period lag beta in the interstate market. This result is consistent with our expectations of the effects of NGPA on interstate pipeline revenue risk. As in the case of financial leverage, the increased revenue risk in the interstate market after 1978 works in the opposite direction from what we would require to explain the significant relative increase in intrastate pipeline asset risk.

³⁵More extended lags proved fruitless.

Table 5
Revenue Betas

Interstate Portfolio (standard errors in parenthesis)

	α	β_{rev_0}	$\beta_{rev_{-1}}$	$\beta_{rev_{-2}}$	SSR	R^2
1972.IV - 1978.I (20 observations)	.082 (.060)	.67 (.57)	-.43 (.55)	-.48 (.56)	1.12	.03
1978.II - 1981.IV (15 observations)	-.02 (.09)	-.03 (.95)	-.45 (.89)	2.56* (1.06)	.69	.19

Intrastate Portfolio

1972.IV - 1978.I (20 observations)	.088 (.02)	.07 (.20)	.02 (.19)	-.15 (.20)	.135	.0
1978.II - 1981.IV (15 observations)	.046 (.03)	.16 (.28)	-.32 (.26)	.26 (.31)	.059	.0

β_{rev_0} = no lag

$\beta_{rev_{-1}}$ = one period lag (3 months)

$\beta_{rev_{-2}}$ = two period lag (6 months)

*Significant at .05 level

4. Conclusions and Limitations

As described in section II, there is substantial anecdotal evidence that interstate pipelines are entering into very different types of vertical market arrangements with gas producers, and that the changes coincide with the partial decontrol of wellhead prices in 1978. In this section we have examined changes in relative asset and revenue risks between the inter and intrastate pipelines as an indirect measure of risk-shifting due to vertical market arrangements in the interstate market. These results, as summarized in the table below, provide evidence complementary to the direct evidence on contract forms cited earlier.

β_{asset} \ β_{rev}	1972-1977	1978-1981
Interstate	.45	.66
Intrastate	.80	1.19 ^b

a - two-period lag significant at .05 level

b - significantly greater than corresponding value for interstate portfolio

The following table compares these results with our prediction of the effects of the partial decontrol of wellhead prices.

	Interstates		Intrastates	
	β_{asset}	β_{rev}	β_{asset}	β_{rev}
Prediction	constant	↑ large	↑	↑
Result	↑ but < intra	↑ large	↑ large	↑ small

We have observed an increase in revenue risk in the interstate market, and it was not accompanied by an increase in asset risk relative to the increase sustained in the intrastate market. The compensating effect of changes in vertical market arrangements may be the cause of the differences.

While these results are suggestive, they should probably not be interpreted too literally, since take-or-pay risk and leverage is only one of many factors which might lead to a change in asset risk. We have accounted for financial leverage, but other factors such as relative changes in market growth opportunities could influence the asset betas and not be discerned by our measure of revenue risk. It is also of some concern that the precision of the revenue beta estimates is low. The seasonality in the quarterly revenue data may tend to swamp any market-correlated variation. A possible alternative to this analysis might be to use the 1954 Phillips decision as the regulatory change of interest, and examine the risk relationships before and after the original imposition of wellhead price controls. The advantage of this analysis would be that a longer time period could be studied and annual instead of quarterly revenue data could be employed.

Finally, we have experienced only a few years of partial wellhead price decontrol. As we progress toward more complete decontrol in the 1980s, the risk-shifting proposition may become even more clearly discernable in the relationship between revenue and asset risks.

In the next section we briefly consider to what extent regulatory policy-makers should be concerned about this risk-shifting behavior.

VI. IMPLICATIONS FOR THE REGULATION OF GAS PIPELINES

Under the "comparable earnings" standard of rate-of-return regulation, the ability of pipeline companies to backward integrate or to alter the terms of their long-term contracts so as to change their level of systematic risk could undermine any attempt by regulators to maintain an efficient risk-return balance. This is, of course, only a subset of the many reasons why the traditional approach to the comparable earnings standard may lead to inefficient regulation. But it is of some interest because it involves a strategic tool at the disposal of the regulated firm and not just a methodological problem in the regulation itself.

A. Ex Ante Regulatory Conditions

To think about the implications of this behavior for FERC pipeline regulation after complete wellhead decontrol, it is necessary to consider the ex ante regulatory conditions (i.e., does FERC currently over or under-compensate pipelines for the risk they bear). The evidence on this point is conflicting. A study by Stephen Breyer and Paul MacAvoy (1974) found that throughout the 1960s the FPC allowed rate-of-return on equity substantially exceeded their estimated cost of equity capital for alternative investments.³⁶

During the entire ten-year period, the allowed rates of return exceeded the estimated costs of

³⁶Stephen Breyer and Paul MacAvoy, Energy Regulation by the Federal Power Commission, Brookings Institution, Washington D.C., 1974, pp.32. Their comparison here is based on a study of the cost of equity capital performed by Robert Litzenberger and Cherukuri Rao, "Estimates of the Marginal Rate of Time Preference and Average Risk Aversion of Investors in Electric Utility Shares: 1960-1966", Bell Journal of Economics and Management Science, Vol. 2, Spring 1971, pp.265-77.

capital for equity investors in the gas pipeline companies. In the early 1960s, allowed equity returns were more than twice estimated equity costs. During 1968 and 1970, costs rose to more than 9.0 percent but were still 1 to 3 points below the allowed limits on equity in eight of the nine cases decided during those two years.

But a comparison of the allowed return on equity with a measure of the required rate of return may not be an adequate test of the strictness of regulation.³⁷ To obtain a second indication of the stringency of regulation, market-to-book value ratios were calculated for our portfolios of inter- and intrastate pipelines during the 1970s. One would expect that efficient regulation based on the comparable earnings standard would lead to market-to-book ratios in the range of one. Values less than one will be a pretty good indication of overly-restraining regulation. The results in Table 6 indicate that this is indeed the case for the 1970s. The unregulated intrastates show market-to-book ratios substantially greater in comparison.

B. Implications and Alternatives

Since the jury is still out on the question of regulatory conditions let us consider both cases. In the first case FERC currently just-compensates or over-compensates pipelines for the risk they bear. In this circumstance if, with decontrol, pipelines are able to shift added risk to producers without adaptation by FERC, they will earn monopoly rents depending on how much risk they are able to shift.

There are two primary alternatives open to the regulatory authority to deal with this case. First, it can modify the allowed rate-of-return

³⁷Stewart Myers points out that, since rate-of-return regulation acts to truncate the upper tail of the distribution of returns, a return higher than a competitive return may be required to adequately compensate pipelines for risk.

Table 6
Gas Pipeline Market-to-Book Value Ratios
1972-1980

	<u>Interstate Portfolio</u>	<u>Intrastate Portfolio</u>
1972	.94	1.57
1973	.79	1.08
1974	.72	.97
1975	.70	1.01
1976	.81	1.14
1977	.75	.97
1978	.64	.83
1979	.70	1.10
1980	.73	1.51

to account for the shifting of risk. Given the difficulty of measuring the effect and the lack of homogeneity in the pipeline industry, this alternative is probably impractical. Second, FERC can create the conditions which would allow customers to undermine the ability of pipelines to earn monopoly rents for whatever reason. That is, by regulating gas pipelines as common-carriers they could allow consumers to contract directly with producers for gas. Pipelines would then be required to provide transportation services on demand, provided they had sufficient capacity. Instead of facing a demand for gas, pipelines would face a demand for transportation services. By getting pipelines out of the business of buying and reselling gas supplies, variable costs of purchased gas and take payments no longer influence pipeline cash flow risk and they are eliminated as mechanisms through which pipeline companies can shift risks.

In the second case to be considered FERC regulation is currently over-constraining. The ability of pipelines to shift risks would serve in this case to improve the efficiency of the process as long as the result is an expected return not greater than the new risk level requires. But this fortuitous result is not occurring by design. It may still be fruitful to consider common-carrier regulation from the point of view of protecting pipelines from the hazards of undercompensation for risk, particularly in light of the potential avenues that state regulatory authorities have to thwart the process of wellhead price decontrol. This latter point is just the tip-of-the-iceberg of issues that deserve further research.


While the functioning of a common-carrier form of regulation is not the subject of this paper's research, can we say anything about the kind of vertical market arrangements we would expect to form under this system of regulation. We do know that the ability and incentive for pipelines to shift risks toward producers would be eliminated with common-carrier status. The number of firms bargaining with any one producer would probably increase and the average contract volume would fall. In all likelihood we would see the emergence of gas brokers, third parties whose function would be to bring buyers of all sizes and producers together in an orderly manner³⁸. And finally, the vertical market arrangement which was alluded to in the introduction to this paper, the spot market, would possibly form both to allocate gas supplies and (with a futures market) to allocate risks. It is difficult to visualize how a fully-functioning spot market would develop without the regulation of pipelines as common-carriers. But this, too, is the subject of future research.

³⁸Indeed, gas brokering has been a common intrastate market phenomenon.

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